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November 17, 2021

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

Re: Docket No. 2019-182-E—South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators (See Docket No. 2020-229-E)

Dear Ms. Boyd:

I am writing on behalf of Dominion Energy South Carolina, Inc. ("DESC") in fulfillment of Order No. 2021-569 (the "Order"), issued in this docket by the Public Service Commission of South Carolina (the "Commission") on August 19, 2021. Specifically, the Order required electrical utilities to provide the following items to the Commission no later than today:

- A narrative (the "T&D Narrative") of how the electrical utility plans to improve data capabilities over time to improve the insight into the transmission and distribution ("T&D") systems to modernize the planning of T&D systems and to modernize the plans of T&D assets to take into account the ability of distributed energy resources ("DERS") to avoid or defer traditional, utility-owned T&D capital investments; and

- A plan (the "Marginal Line Loss Plan") to acquire the capability to determine marginal line loss data associated with customer-generator facilities, if such capability does not already exist.

The T&D Narrative and Marginal Line Loss Plan are detailed on **Exhibit A** and contain action items and corresponding milestones for both DESC's Transmission and Distribution personnel. Allocating action items in this way is appropriate because customer-generators and corresponding DERs affect each system differently. For example, although a small number of DERs in a specific location may have the potential to impact distribution planning, the transmission system is part of the larger interconnected Bulk Electric System. As such, specific locational factors or small reductions in load at a given substation generally will not impact required transmission investments.

Likewise, DESC recognizes that acquiring the capabilities to determine the impact of DERs on its system is a complex process that will benefit from a collaborative exchange of information and ideas. Therefore, as outlined on **Exhibit A**, DESC proposes to host an initial stakeholder meeting to inform DESC's efforts going forward, all in accordance with the below plans and implementation schedule. DESC appreciates the opportunity to present this plan to the Commission.

Very truly yours,

Matthew W Gissendanner

Matthew W. Gissendanner

MWG/kms

cc: Adam Protheroe, Esquire
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(all via electronic mail and U.S. First Class Mail w/enclosures)

<u>EXHIBIT A</u>

T&D Narrative and Marginal Line Loss Plan

I. T&D NARRATIVE

The data and processes required to assess the role of customer-generators in capacity planning decisions is complex. Accordingly, as an initial step, DESC proposes to facilitate a meeting of interested parties and industry stakeholders by the second quarter of 2022 to address and inform DESC's proposed responses for several of the topics and proposed data acquisition and planning activities outlined in the following narrative. Industry stakeholders and interested parties would be contacted via public notice, and DESC would also publish that notice in this docket.

Distribution

Customer-Generator Data. The output of renewable resources varies due to seasonal factors such as lower solar irradiance or changes in output due to cloud cover. The temporal changes in renewable resource output is a critical factor in DESC's distribution planning, as the availability of these resources at the time of need must be comparable to traditional distribution capacity investments. DESC recognizes the need to enhance data collection and estimation of time-varying output of existing and future customer-generator resources. The granularity of data collected is an important consideration, as rapidly changing output caused by cloud cover or other environmental factors, in addition to resource status (e.g., devices that have been disconnected or producing less output) or condition, can reduce output during periods of high electric demand or degrade power quality that must be addressed and incorporated into DESC's capacity planning processes.

DESC currently collects interval output data from customer-generators via separate meters. Currently, data management systems and tools needed to determine customer-generator output on an hourly or subhourly basis are not yet in place. DESC will need to upgrade its meter data interfacing systems to perform "live mapping" of customer-generator and Advanced Metering Infrastructure ("AMI") meter data to DESC's Geographic Information System. While this is needed, as explained above, this is a significant endeavor. Further, DESC plans to obtain supplemental distribution power flow software required to analyse variable output from renewable generation on an hourly or subhourly basis.

DESC also plans to assess the feasibility of updating systems needed to collect and align hourly (and subhourly) customer-generator and AMI data in a format suitable for upload to distribution software. This will aid in determining the value of potentially deferral distribution investments. In addition, DESC also proposes to monitor and evaluate renewable energy output and performance obtained from industry research and demonstration projects on an ongoing basis—preferably at locations within South Carolina—in order to gain increased understanding of non-traditional resource output profiles and variability.

Load and Capacity Forecasts. DESC's distribution capacity forecasting process is based primarily on non-coincident peak demand (NCP) derived from recent loading data, with seasonal adjustments for equipment loading limits such as substation transformers. DESC does not adjust distribution historical peak loads because they are embedded in its distribution forecast as a net load reduction. Substation and feeder hourly profiles are not tracked due to the absence of interfacing tools needed to map AMI and customer-generators. The unavailability of hourly load profiles that includes adjustments for customer-generator output has not been a major concern to DESC planners thus far due to the relatively small amounts of renewable energy currently installed in DESC's service territory.

Prospectively, DESC will assess the need and method by which to best incorporate customer-generator output profiles into peak and off-peak forecasts following its assessment of the systems and tools needed to collect and align AMI and customer-generator data, and how the data would be used to evaluate the impact of rapidly changing renewable resource output as outlined in the Distribution Technical Analysis section below. DESC expects this topic will be addressed in the industry stakeholder meeting described above.

DESC proposes to modify its distribution forecasting and capacity planning processes over time as DERs are added to include increased granularity such as developing capacity forecasts based on seasonal and time-of-day adjustments for resources. The source of these adjustments will include the additional data outlined in the Customer-Generator Data section above and use of proxy or benchmark data in the alternative. DESC will also address the potential role and value of customer-generators in distribution capacity planning processes and decisions pending the outcome of DESC's assessment of tools and system needed to collect and integrate the data into existing and new distribution simulation tools.

Locational Capacity Investments. Currently, DESC planning activities include the development of year-ahead and longer-term annual capacity investment plans for individual distribution substation and feeders. These plans include determination of the magnitude of annual capacity deficits over time and the preferred conventional solution to address the deficit. These plans identify the cost of avoided capacity investments by location for each year over the capacity planning horizon. DESC separates those investments that are needed for non-capacity reasons. DESC concludes the level of granularity in these investment forecasts meet the Commission's Order to identify capacity related investments on a more granular basis; that is, determining distribution capacity needs at specific locations within DESC's service territory.

As described in the prior section, DESC proposes to assess the role of customer-generators in capacity planning processes and decisions. Depending on the outcome of DESC's assessment, this may include identification of the hours of need for capacity investments, by season and time-of-day, with adjustments to hourly demand based on customer-generator output as such data becomes available. In addition, DESC will assess factors such as the minimum lead time needed to commit to pursuing distribution investment decisions, as any future programs designed to defer traditional distribution system investments such as Non-Wires Alternatives ("NWA") must provide assurance that sufficient firm capacity will be available at the time a decision must be made to either pursue or defer the investment.[1]

Distribution System Technical Analysis. DESC recognizes that a technical analysis using industry-accepted methods and tools is essential to accurately assess and predict the impact and potential value of non-traditional resources such as solar. DESC currently uses Eaton's CYME distribution simulation model for engineering and planning applications. These studies include static distribution power flow analysis for a subset of peak and off-peak loading conditions; typically, four discrete hourly intervals per year using data from DESC's GIS. As such, DESC believes these capabilities meet the current needs of DESC's engineering and planning organizations.

Because of hourly and sub-hourly variances in renewable energy output, DESC recognizes that it will eventually need to enhance its distribution simulation modelling tools and evaluation methods to address increasing amounts of non-traditional resources such as solar. As increases in renewable or other non-traditional capacity increases to a level where more detailed analyses are required and data needed to conduct the more detailed hourly and sub-hourly power flow simulation studies is obtained, DESC will acquire and apply advanced distribution

[1] Minimum lead time for capacity investment include factors such as planning, design, permitting and regulatory approval, where applicable, equipment procurement, construction, and testing and commercialization.

simulation modelling capabilities such as time series and dynamic analysis capabilities into its suite of distribution planning tools. Future applications may include active inverter control modes as adopted by updates to the IEEE DG interconnection guidelines (1547-2018) or determination of hosting capacity limits on circuits with future load-related investments. DESC will also assess and report on how it would propose to apply adjunct CYME simulation models or other tools that perform these more detailed functions pending its assessment of updates of its AMI and customer-generator data interfacing systems to enable the modelling of distribution circuits using hourly and subhourly data.

Distribution Planning and Design Criteria. DESC will evaluate the need and feasibility of updating its current distribution planning processes and methodology based on distribution data acquisition and software additions described in the prior sections. Potential revisions could include incorporating existing and future customer-generator output data in peak and non-peak hourly forecasts and technical assessment of these sources on DESC's distribution planning criteria. DESC expects this topic will be addressed in the industry stakeholder meeting described above.

Grid Modernization and Resource Management. DESC proposes to assess, at a high level, potential system modernization and enhancements needed to assess customer-generator output and more generally, DER as an alternative to traditional capacity investments, in addition to operational systems that may be needed as the amount of customer-generator output increases in DESC's service territory. For example, in conjunction with its assessment Distribution Planning and Design Criteria described above, DESC proposes to qualitatively assess how increases in customer-generator output and resulting two-way power flows may impact distribution design, equipment selection and system protection. In addition, DESC will assess the need to enhance operational technologies such as Advanced Distribution Management Systems (ADMS) and Distribution Energy Management Systems (DERMS) to improve visualization and distribution system control functionality to accommodate complexities associated with increasing amounts DER.

<u>Transmission</u>

Data Requirements. Data needed to analyse customer-generator impacts on DESC's transmission system is obtained mostly at the distribution level. For example, distribution load and DER forecasts are aggregated at individual substations to support transmission planning activities. Currently, DESC conducts transmission planning studies of its bulk electric system ("BES") in conformance with the DESC Transmission Planning guidelines and North American Electric Reliability Corporation ("NERC") reliability standards. DESC is required to adhere to clearly defined transmission planning criteria for normal and contingency conditions per the NERC standards. Most transmission investments on DESC's bulk electric system are for reliability, contingency support, transfer capability improvements and other non-load related reasons. The primary change under consideration with respect to DESC's transmission investments is the modelling of adjusted load forecasts at transmission substation banks based on the aggregated impact of NEM DERs on those respective loads. Once the distribution data is available, an assessment can be made as to whether the aggregated NEM impact is large enough to defer any transmission upgrades.

Bulk System Versus Local Transmission Investments. Because DESC's transmission system operates as part of the larger interconnected BES, both within and outside of the Southeast Reliability Corporation (SERC) East Subregion, system enhancements and investment typically are required to support the entire network. Hence, specific locational factors or small reductions in load at a given substation generally will not change needed transmission investments. The potential for DER to defer transmission system investments, albeit small compared to other investment categories, should be determined on an aggregate basis over the entire DESC system. In contrast, the number of capacity-related investments on DESC's lower voltage transmission is higher and more locational, particularly for radial lines and substations serving load centers. DESC will use the data captured by AMI for customer-generators and aggregate the impact to the transmission substation level.

II. MARGINAL LINE LOSS PLAN

Distribution

DESC proposes to continue to apply its current approach for deriving losses for its distribution system, which is based on a rigorous analysis of metered data that reconciles with measured data. DESC proposes to provide increased granularity by applying its current approach to representative circuit types. The approach recognizes that marginal losses vary significantly based on factors such as voltage level, line length and load distribution. DESC proposes to apply an industry-accepted statistical approach to identify representative circuits and derive marginal losses for each. DESC proposes to calculate losses by load level and time of day via the creation "loss curves" for the representative feeders. The loss curves are based on the calculation of losses at increasing feeder loads and create a curve fit based on a subset of loss factors. These loss curves can be used to interpolate or extrapolate losses based on hourly loads.

Transmission

Similar to distribution, DESC proposes to continue to apply its current approach to determine transmission losses, where marginal losses are equal to average losses. DESC expects the accuracy of data at individual substations will improve with the availability of AMI data. However, DESC does not propose to derive transmission losses for specific lines or locations. The rationale for derivation of system-wide marginal losses is due to the fact DESC's transmission is configured as a network and the level of analysis required to predict losses at each location (e.g., transmission mode) is not warranted or necessary. Output from customer-generators will typically cause losses to decline across the entire network. Further, transmission system losses vary due to changes in loads, line outages, generation dispatch, interchange, and loop flows—each of which increases the complexity of attempting to derive losses at individual nodes or locations.

DESC proposes a two-phase approach. The first phase will include development of a process to capture transmission network losses obtained from DESC's Energy Management System (EMS) under a range of load and generation dispatch conditions. Similar to distribution, "loss curves" of the transmission network will be created based on the calculation of system losses at increasing loads. The resulting curve fit can then be used to interpolate or extrapolate losses by time of day based on system loads. The second phase, which will be performed following completion of the first phase, will assess the feasibility of deriving marginal losses on a seasonal or time of day basis.

III. IMPLEMENTATION SCHEDULE

Listed in the table below is DESC's high-level schedule for implementing the items described above. DESC expects that much of the data needed to accurately forecast avoided investments on a more granular basis will be collected over one or more years, with the level of detail increasing as more data is obtained and analysed.

Category/Description	Proposed Schedule
Industry Stakeholder Meeting	1st/2nd Quarter 2022
(1) Avoided Distribution Investments	
Customer-Generator Data	06/2022
Load and Capacity Forecasts	09/2022
Locational Capacity Investments	12/2022
Distribution System Technical Analysis	06/2023
Distribution Planning and Design Criteria.	12/2023
Grid Modernization and Resource Management	Ongoing
(2) Transmission	
Data Requirements	12/2022
Bulk System Versus Local Transmission Investments	12/2023
(3) Marginal Losses	
Distribution	12/2022
Transmission	12/2022

(end)